

ADVANCED COGAS POWER SYSTEMS FOR LOW POLLUTION EMISSIONS

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ABSTRACT

Analytical studies have been conducted to define commercially feasible, advanced-technology central power stations which would eliminate or significantly reduce utility-caused atmospheric pollution and thermal water pollution. The basic concept investigated represents a combination of (1) advanced cycle, Combined Gas And Steam (COGAS) turbine electric power generation systems based on technology spin-off from the aircraft gas turbine industry, and (2) selected processes for deriving nonpolluting gaseous fuel from high-sulfur residual fuel oil.

The results of these studies clearly indicate that advanced COGAS power systems integrated with fuel gasification systems would be more effective than future fossil steam systems in controlling emissions of ash, sulfur oxides, and waste heat. In addition, preliminary calculations indicate that emissions of nitrogen oxides could be reduced up to several orders of magnitude by using low-Btu gasified fuel compared with emissions caused by the combustion of high-Btu fuels. It appears that advanced gas turbine and COGAS power systems using low-Btu fuels could be fired to higher turbine inlet temperature to improve performance and still emit significantly less nitrogen oxides than when operating at low turbine inlet temperature with high-Btu fuels. Furthermore, prospective COGAS systems could produce electricity at lower cost than could be produced by alternative fossil steam systems with comparable air and water pollution controls. Also, despite the relatively high cost of fossil fuels, advanced COGAS power systems should offer a viable alternative to nuclear power systems for future base-load power generation.

INTRODUCTION

The electric utility industry in the United States is currently the target of numerous regulatory agencies and environmental groups whose goal is the elimination or significant reduction of objectionable emissions such as sulfur oxides, nitrogen oxides, particulate matter, and waste heat. A number of exploratory studies and demonstration projects are being carried out on methods of reducing power station

pollution. While some stack gas cleaning methods show promise, the only proven method currently available for the reduction of sulfur oxides is the use of relatively expensive, low-sulfur fuels. Similarly, the only available methods for the reduction of nitrogen oxides involve combustion modifications. All of these methods have the disadvantage of increasing the cost of generating power because of their high capital and operating costs.

An alternative method of pollution control involves the conversion and cleanup of dirty coal or residual fuel oil prior to combustion. Such fuel treatment would result in a significant increase in the cost of fuel delivered to the power generating system. In order to offset this increased fuel cost, the thermal efficiency of electric power generation should be increased as much as possible by using advanced-cycle power systems.

Several feasibility evaluation studies of advanced-cycle power systems have been conducted by the United Aircraft Research Laboratories, including one for the Environmental Protection Agency (formerly National Air Pollution Control Administration of the Department of Health, Education, and Welfare) reported in Ref. 1 and another for the Connecticut Development Commission reported in Ref. 2. The results of these studies indicate that power systems incorporating advanced-design gas turbines used in conjunction with steam turbines and gasification systems producing low-Btu fuel offer the potential of essentially eliminating the air and thermal water pollution problems of electric utilities while simultaneously producing lower-cost power than is projected for conventional steam systems. Previous papers summarizing the results of these studies have dealt primarily with the design, performance, sulfur emission control, and cost characteristics of advanced-cycle power systems operating on gasified coal (see Refs. 3 and 4, for example). This paper briefly summarizes these same characteristics for advanced-cycle systems operating on gasified residual fuel oil, with emphasis placed on the lowered nitrogen oxide emission characteristics anticipated for gas turbine systems operating on low-Btu gaseous fuels.

ADVANCED COGAS POWER STATIONS

The generic type of power system that shows the most promise for effective pollution control consists of a gasification process producing a clean, low-heat-content fuel gas for use in a Combined Gas And Steam (COGAS) turbine power system. Unlike some present-day COGAS systems in which the gas turbines are essentially air preheaters for the steam boiler, advanced-cycle COGAS systems would utilize large industrial gas turbines operating at high turbine inlet temperature. The technology basis for these gas turbines represents spin-off from the aircraft gas turbine industry. These gas turbines would produce approximately 60% of the net

station electric output, and their exhaust gases would be directed into waste-heat boilers which would generate steam for a steam turbine system producing the remaining 40% or so of the net station output.

Advanced Gas Turbine Technology

By adapting recent and continuing advances in aerospace technology to industrial turbine machinery design, substantially improved large capacity gas turbine power systems with appreciably higher thermal efficiency could result, leading to their widespread use in intermediate-load and base-load power generation applications. These advances in aerospace technology were achieved during extensive research and development efforts on military and commercial aircraft gas turbines and include improvements in materials technology, blade cooling techniques, aerodynamic flow path design, high-heat-release burners, and modular fabrication techniques.

While meaningful improvements in aerodynamic performance are projected for future gas turbines, the most significant future technological advances are expected in the area of turbine inlet temperature. Current industrial gas turbines are limited to turbine inlet temperatures of approximately 1800 F for base-load ratings. Part of the projected increase in turbine inlet temperature will be achieved by the use of improved turbine blade materials. Historically, maximum turbine blade temperatures have advanced approximately 20 F per year because of improvements in materials and coatings. Recently, however, significant increases in turbine inlet temperature approaching 70 to 80 F per year have been achieved in aircraft gas turbines through substantial improvements in turbine cooling techniques in combination with newer materials. Aircraft gas turbine engines beginning commercial operation during the early 1970s will operate at turbine inlet temperatures of approximately 2100 F during cruise and up to 2400 F during takeoff.

By applying the same sophisticated convection-cooled blade design philosophy to industrial engines and by precooling the turbine cooling air before being utilized in the turbine for cooling purposes, it should be possible to begin designing a new 2200 F industrial engine which could be put into commercial base-load operation in the near future. Further improvements in materials, oxidation-resistance coatings, and more advanced cooling concepts should permit base-load operation at turbine inlet temperatures on the order of 2600 F by the early 1980's. A conceptual design for a 100-Mw class simple-cycle gas turbine designed for 2600 F turbine inlet temperature and 20:1 compressor pressure ratio is depicted in Fig. 1. By the 1990's industrial gas turbine inlet temperatures of 3000 F or higher should be in commercial operation.

Waste-Heat Recovery in COGAS Systems

A simplified schematic diagram for an integrated COGAS/oil gasification power station is illustrated in Fig. 2. All the desulfurized fuel gas would be delivered to the gas turbine burner and the main heat recovery boiler would be unfired. In the short term, before turbine inlet temperatures are increased appreciably, it may be desirable for some applications to burn additional fuel in the boiler. This would increase output power and might result in lower emissions of nitrogen oxides per unit of output power. In the long term, however, when turbine inlet temperatures exceed approximately 2200 F, unfired heat recovery systems would result in highest overall efficiency and lowest overall cost.

During operation of an integrated COGAS/oil gasification power system, de-aerated feedwater from the main heat recovery steam cycle would be passed to the fuel gas waste heat boiler and converted into saturated steam at the same pressure as the high-pressure steam raised in the main steam cycle. Some of this high pressure saturated steam could be used to preheat the oil feed to the gasifier and some could be injected into the gasifier. The balance would be returned to the main steam cycle to be superheated along with the steam generated in the main boiler. The resulting superheated steam would be expanded in steam turbines to drive an electric generator and the booster air compressor.

Previous cycle studies (Ref. 1) have demonstrated that when the inlet gas temperature to the main boiler is below approximately 1200 F, single-pressure steam systems would result in stack temperatures in excess of 300 F. By adding a second low-pressure steam cycle, as depicted in Fig. 2, it is possible to extract additional heat from the stack gases and drop the stack temperature to 300 F, thereby improving steam cycle efficiency.

RESIDUAL FUEL OIL GASIFICATION AND CLEANUP SYSTEMS

The availability of clean, desulfurized fuel is an absolute requirement for the type of advanced gas turbines described in the previous section, and processes for producing such clean fuels from high-sulfur coal and oil are expected to become available concurrently with the advanced power systems. Processing high-sulfur residual fuel oil to produce clean, low-sulfur, gaseous fuel involves partial oxidation in a high-pressure reactor vessel to produce a hot, gaseous raw fuel (see Fig. 2). The hot, raw fuel gas would be cooled in heat exchangers and waste heat boilers, water scrubbed to remove carbon and soot particles, and then passed through an absorption system to remove sulfur compounds. The resulting fuel gas composition, after scrubbing and desulfurization, would be approximately 13-16% H_2 , 20-25% CO , and 55-60% N_2 (by volume). Smaller concentrations of H_2O , CO_2 , CH_4 , A, sulfur

compounds, and nitrogen compounds would be present. The heating value of the clean fuel gas would vary from approximately 120 to 140 Btu/scf, depending on operating conditions. The desulfurized fuel gas would then be passed to the power system, and the sulfur compounds would be processed to produce elemental sulfur.

Partial Oxidation of Residual Fuel Oil

The partial oxidation of liquid-hydrocarbons is well-developed technology with numerous plants in operation working on a wide variety of feedstocks. The partial oxidation process was developed for the production of synthesis gas or hydrogen in the early 1950's by Texaco Development Corporation in the United States and Shell Internationale Petroleum Maatschappij N.V. in Europe. Both of these companies have made recent contributions to the technology of noncatalytic partial oxidation of hydrocarbons and have processes for license.

Generally, the partial oxidation process is very flexible in its operating characteristics. When used to produce fuel gas, feedstock (oil), air, and sometimes steam (to increase the hydrogen yield and to help control temperature) would be preheated and mixed before entering the refractory-lined reaction chamber. The oil feed would be converted into desirable products (hydrogen, carbon monoxide, and methane), undesirable products (hydrogen sulfide, carbonyl sulfide, carbon dioxide, and water vapor), diluents (nitrogen and argon), and soot (carbon) which would be recycled to extinction. The relative amounts of carbon monoxide and hydrogen would depend on the air/oil ratio, steam/oil ratio, oil composition, preheat temperatures, and pressure.

Sulfur Removal and Recovery from Raw Fuel Gas

During scrubbing and desulfurization operations, most of the H_2O , 50 to 70% of the CO_2 , and over 95% of the sulfur compounds would be removed from the fuel gas stream. The sulfur originally present in the fuel oil would appear in the raw gas principally as hydrogen sulfide, H_2S , with small but important quantities of carbonyl sulfide, COS . There is a wealth of technological data (see Refs. 5 and 6) available for the removal of H_2S from hydrocarbon gases, largely due to the development of the natural gas industry during the past 30 years.

Two types of chemical-solvent scrubbing systems look very attractive for the removal of sulfur compounds in power generation applications: hot potassium carbonate and amine scrubbing systems. The hot potassium carbonate scrubbing process was developed by the Bureau of Mines for the removal of CO_2 from coal gas to upgrade its heating value. It was discovered that H_2S and COS were also effectively removed. Amine scrubbing systems have been highly developed and are popular methods for removing CO_2 and H_2S from natural gas. These methods are based on employing monoethanolamine (MEA), diethanolamine (DEA), di-isopropanolamine, or other scrubbing solvents.

The desulfurization of fossil fuels usually requires some plan for the disposition of the sulfur compounds which are removed from the raw fuel gas. Various schemes have been developed to recover the sulfur in a form that has economic value. The most important of these schemes, which involve the selective oxidation of H_2S to elemental sulfur, have been classified together as Claus systems. By proper design of the scrubbing and Claus systems (incorporating, for example, multiple stages and improved designs), it is possible to achieve an overall sulfur removal effectiveness of 85 to 96%. By further treating or recycling of the tail gas from the Claus system it should be possible to exceed 98% overall sulfur removal effectiveness.

CHARACTERISTICS OF INTEGRATED COGAS/OIL GASIFICATION POWER STATIONS

Selected characteristics of integrated COGAS/oil gasification power systems corresponding to three levels of technology (present day plus technology projected to be available during the mid-1970's and early 1980's) are presented in Table I. The general requirements and design characteristics for the gasification system, gas turbines, and waste heat recovery steam system are summarized in the table along with selected performance data for the integrated power stations. The net station outputs range from 159 to 309 Mw, and the estimated net station thermal efficiencies range from 32% to 40%. These net station efficiency estimates could possibly be increased as much as 3 points by further cycle optimization combined with the use of higher temperature (1300-1500 F) fuel gas delivered to the gas turbine burner. Higher fuel gas temperature might be feasible in future systems by using high-temperature desulfurization and cleanup or an improved gasifier heat recovery scheme which would regenerate clean, low-temperature fuel gas against raw, high-temperature fuel gas.

Also indicated in Table I are estimated emission rates for sulfur oxides, nitrogen oxides, and thermal heat rejection to the cooling tower circuit. Sulfur emissions would be low because of the desulfurization process incorporated in the gasification system. Nitrogen oxide emissions would be low because of the favorable combustion characteristics of low-Btu gasified fuel as described in the next section.

All conventional power generating equipment (with the exception of simple-cycle gas turbines) reject heat to cooling water. The rates of heat rejection from fossil- and nuclear-fueled steam stations are approximately 4300 and 6600 Btu/kwhr, respectively. COGAS stations would have significantly lower heat rejection rates (as much as 30% lower than fossil and 50% lower than nuclear stations), as noted in Table I, due to their high thermal efficiency and increased heat rejection rate to the atmosphere. The impact of this heat rejection on cooling water supplies could be reduced for all types of power systems by the use of cooling

towers. Wet (evaporative) cooling towers might, under certain circumstances, cause objectionable fogging at ground level, and dry (nonevaporative) towers are very expensive. The environmental and economic impact of using cooling towers for COGAS systems would be significantly less than for the alternative systems because of the reduced heat rejection rate of COGAS systems.

NITROGEN OXIDE EMISSIONS FROM GAS TURBINE POWER SYSTEMS BURNING LOW-BTU FUEL GAS

Oxides of nitrogen are receiving increasing attention as air pollutants. The oxides NO (nitric oxide) and NO₂ (nitrogen dioxide) are commonly lumped together as NO_x. They are easily interconverted in the atmosphere, and their ratio changes depending on the action of sunlight, oxygen, and other oxidizing or reducing agents present. Nitrogen oxides are formed in the hot reaction zones of all air-breathing combustion engines. They are formed primarily as NO, although small quantities of NO₂ and N₂O (nitrous oxide) may also be formed.

Control of NO_x emissions from gas turbines can be accomplished in either of two ways: (1) preventing NO formation by fuel pretreatment and/or by careful design and operation of the burner, and (2) removal of NO_x compounds after combustion from the exhaust gases. This paper deals with the first alternative because removal of NO_x compounds after their formation is likely to prove far more difficult and costly (see Ref. 7).

Nitric Oxide Formation Mechanisms

Two mechanisms are known to contribute to the formation of nitric oxide in combustion systems. The most important mechanism for gas turbines and other systems which burn relatively clean fuels is referred to as the thermal or hot air mechanism. In this mechanism, nitrogen and oxygen from the atmosphere react in the hot combustion zone to form nitric oxide. The second mechanism is important when relatively dirty fuels such as coal and residual fuel oil are burned. Most dirty fuels contain small but significant quantities of organic nitrogen compounds. Because nitrogen-carbon and nitrogen-hydrogen bond energies are so much lower than that for molecular nitrogen, much of the fuel nitrogen becomes oxidized during combustion. Experimental studies (Ref. 8) of the formation of nitric oxide from fuel nitrogen indicate that the formation rates are very rapid, occurring on a time scale comparable to that of the hydrocarbon combustion reactions. This mechanism is strictly fuel dependent and proceeds at lower temperatures than needed for the thermal mechanism.

Fuel nitrogen should not be a problem in systems using gasified fuels. During gasification of dirty fuels, some fuel nitrogen would carry over into the raw fuel gas as combustible nitrogen compounds (primarily ammonia, with smaller concentrations of hydrogen cyanide, pyridine, pyridine bases, and acidic nitrogenous compounds). If retained in the fuel gas, these compounds could result in excessive emissions of nitrogen oxides. Fortunately, considerable literature on the removal of these nitrogen compounds from gaseous streams is available (Ref. 6, for example). Before the advent of synthetic ammonia processes, by-product ammonia from gasification and carbonization processes constituted the most important source of fixed nitrogen. Practically all processes in commercial use for removal of ammonia are based on washing the gas stream either with water or a strong acid. Successful attempts (see Ref. 5) have been made to develop processes for the simultaneous removal of hydrogen sulfide and ammonia, recovering both compounds in the form of ammonium sulfate and elemental sulfur. Most other nitrogen compounds would be eliminated in the normal course of removing ammonia from the gas stream.

The chemical kinetics of NO formation via the thermal mechanism are fairly well understood (Refs. 8 and 9). Three variables of primary importance in NO production are local temperature, residence time, and chemical species concentration. Unfortunately, it is extremely difficult to relate these primary variables to the geometry and operating characteristics of practical gas turbine combustors due to limitations in analytical combustor modeling techniques. Previous investigations of NO formation kinetics (Refs. 10 and 11) have identified several significant simplifying assumptions which appear to apply to gas turbine burners. The most important of these are the following: (a) the NO formation rate is very slow relative to the hydrocarbon combustion reaction rates; and (b) within the uncertainty of known rate constants and present combustor models, it appears that the hydrocarbon chemistry can be decoupled from the kinetics of NO formation, i.e., the concentrations of all species except nitrogen compounds can be assumed to be in thermodynamic equilibrium at the local temperature and fuel/air ratio.

Under these conditions, the elementary reactions of importance in NO formation are:



Reactions (1) and (2) are the principal reactions, with (1) being the rate controlling reaction. Reaction (3) is of minor importance in fuel-rich mixtures.

A simplified kinetic model based on the above reactions was programmed for solution on a digital computer and combined with a program which calculates equilibrium thermodynamic properties and species concentrations. This model can be applied to a steady flow process where the temperature-time-composition histories of the fluid elements in the flow are known.

Before presenting NO emission estimates for gas turbine burners, it is instructive to consider idealized fluid elements in the flow as combustion products of uniform temperature, pressure, and composition (with the exception of nitrogen compounds) and to investigate the increase in NO concentration with time for conditions which are considered to be typical of gas turbine burners. Typical computer results are presented in Figs. 3 and 4. Figure 3 depicts NO concentration vs time estimates for a number of different types of fuels, including a range of low-Btu fuels, all supplied at room temperature. Figure 4 depicts similar results for a single low-Btu fuel supplied at a range of temperatures. The flame temperatures denoted in these figures represent the local temperature in the primary combustion zone of a gas turbine burner and should not be confused with the turbine inlet temperature which would be much lower. The strong dependence of NO formation on temperature and fuel heating value is evident from these figures.

Nitric Oxide Emissions from Gas Turbine Burners

The local temperature, residence time, and species concentrations which govern NO production are controlled by engine operating conditions, the combustor internal flow field, fuel nozzle characteristics, and the air addition schedule to the burner can. Lack of an adequate analytical description of the combustor flow field and the fuel/air mixing characteristics has prevented accurate estimation of the temperature-time-concentration history which is essential for reliable estimation of NO formation. At the present time, several engineering and research establishments, including several groups within United Aircraft Corporation, are attempting to develop comprehensive gas turbine combustor models. The results of this modeling work have been very encouraging and are leading to a better understanding of NO emissions.

A relatively simple three-zone burner model developed by the Combustion Group at Pratt & Whitney Aircraft (Ref. 11) was modified to permit consideration of low-Btu fuel combustion. Results of preliminary NO calculations using this model are presented in Fig. 5. The predicted NO concentrations in the burner exhaust are plotted against the maximum combustion or flame temperature in the primary zone. These calculations were based on a typical burner air and fuel flow distribution for a representative industrial gas turbine. The specific NO emission predictions for CH₄ and JP-5 shown by the individual points in Fig. 5 agree reasonably well with measured data. For low-Btu fuels with combustion temperatures in the 3600 to 4200 F range NO emissions below 10 ppm, and perhaps approaching 1 ppm, appear to be feasible.

The NO emission estimates presented in Fig. 5, although preliminary, are very encouraging and suggest that the use of low-Btu fuels would provide a very effective method of NO control for gas turbines. Furthermore, it seems evident that gas turbines using low-Btu fuels could be fired to high turbine inlet temperature and still emit significantly less NO than low-temperature gas turbines using high-Btu fuels. It should also be noted that these estimates have not taken into account additional NO control techniques such as steam or water injection and off-stoichiometric combustion. Utilization of these techniques, together with low-Btu fuels, might permit even further reduction of NO emissions.

ECONOMICS OF FUTURE POWER GENERATION

Historically, the electric utility industry successfully reduced the cost of generating power by utilizing the latest available technology and taking advantage of economics associated with large-scale generation facilities. This era of decreasing costs of electricity has ended, and we are now on the threshold of a new era with rising costs. This unfortunate situation is a direct result of rapidly rising construction and fuel costs, combined with public demands for effective control of atmospheric and thermal water pollution. Rising costs plague all methods of power generation, both fossil and nuclear. At the present time, nuclear stations are more economical than fossil stations in many parts of the country. But this situation may change as advanced COGAS power stations, incorporating high-temperature gas turbines with fuel gasification and desulfurization systems, become a commercial reality.

The busbar cost of power is the annual owning and operating expense divided by the annual kwhr generated. The annual owning costs include the capital charges due to depreciation, interest, taxes, and insurance; and the operating costs include maintenance, supplies, and fuel. The estimated capital costs for integrated COGAS/oil gasification power stations are summarized in Table II for three levels of gas turbine technology. All costs are presented in terms of estimated mid-1970's dollar value. The total installed capital costs range from \$211/kw to \$303/kw, depending on technology.

Annual owning and operating cost estimates are also summarized in Table II. Maintenance costs for the fuel processing system are based upon guidelines applicable to the chemical process industry, and corresponding costs for the power equipment are based on actual experience and projections. Fuel costs are taken to be 53.4¢/10⁶ Btu for high-sulfur oil in the Northeast. The resulting busbar power cost estimates range from 11.1 to 15.5 mills/kwhr depending on technology.

The power cost estimates presented in Table II are high by today's standards, but cost estimates for alternative methods of power generation with corresponding pollution control measures could be as high or higher, as depicted in Fig. 6. The 1975 EPA and 1973 Connecticut standards could be met by using low-sulfur oil or by adding stack gas cleanup, but doing so would increase the cost of generating power by 15 to 25% relative to a conventional steam station burning high-sulfur (2.6%S) oil. The use of gasified oil in steam or COGAS systems using present-day technology would satisfy the most stringent emission regulations in large cities, but doing so would increase the cost of generating electricity by 30 to 40% (relative to stations burning high-sulfur oil). As technology advances to permit higher turbine inlet temperatures and less costly gasifiers, COGAS systems will be capable of producing lower-cost clean power than alternative fossil steam systems. Furthermore, it appears that COGAS stations based on future gas turbine technology could also compete with future nuclear power generation, despite the relatively high cost of fossil fuels.

CONCLUSION

Advanced COGAS electric power stations consisting of gas and steam turbines integrated with residual fuel oil gasification systems should offer a viable alternative for future base-load generation applications. These stations could improve the environment by essentially eliminating the air and thermal water pollution problems caused by the generation of base-load power, and do so at competitive costs.

Although there are no basic technological problems which have to be solved before COGAS power stations could be built using present-day technology, advanced design and development programs should be energetically pursued to secure the benefits in performance and economy obtainable by advanced technology. Gas turbine technology is expected to increase during future years until turbine inlet temperatures in excess of 3000 F are achieved. COGAS stations designed with these advanced gas turbines, improved heat recovery steam cycles, and improved gasification systems would be very attractive. The eventual use of gasified coal in COGAS stations would further improve the economic potential of these stations.

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TABLE I
SELECTED CHARACTERISTICS OF INTEGRATED
COGAS/OIL GASIFICATION POWER STATIONS

	Level of Technology		
	Early 1970s	Mid 1970s	Early 1980s
<u>Fuel Processing System</u>			
Number of Gasifiers	2	2	2
Residual Fuel Oil Flow, lb/hr	93,600	118,000	144,000
Clean Fuel Gas Output, lb/hr	620,000	781,000	954,000
Clean Fuel Gas Temperature, F	95	520	550
Fuel Process Hot Gas Efficiency, %	70	74	76
<u>Gas Turbines</u>			
Number of Gas Turbines	4	2	2
Nominal Output per Gas Turbine, Mw	23	66	94
Compressor Pressure Ratio	13	16	20
Turbine Inlet Temperature, F	1800	2200	2600
Gas Turbine Thermal Efficiency, % (HHV)	30	32	37
<u>Waste Heat Recovery Steam System</u>			
Number of Steam Turbine Generators	1	1	1
Gross Steam System Output, Mw	80	110	136
Throttle Steam Temperature, F	700	870	980
Throttle Steam Pressure, psia	865	1250	1500
Net Steam System Efficiency, %	27	29	30
<u>Integrated Station</u>			
Net Station Output, Mw	159	228	309
Net Station Efficiency, % (HHV oil)	32	36	40
Sulfur Oxide Emissions, lb SO ₂ /10 ⁶ Btu	0.1-0.2	0.1-0.2	0.1-0.2
Nitrogen Oxide Emissions, lb NO ₂ /10 ⁶ Btu	0.004-0.1	0.01-0.1	0.01-0.2
Heat Rejection, Btu/kwhr	4500	3700	3100

TABLE II
COST SUMMARY FOR INTEGRATED COGAS/OIL GASIFICATION POWER STATIONS

Based on Estimated Mid-1970s Dollar Value

	Level of Technology		
	Early 1970s	Mid 1970s	Early 1980s
Capital Costs, 10 ⁶ \$			
Fuel Processing System (96% S removal)	14.6	15.9	16.8
Gas Turbines	8.4	9.5	12.0
Steam System	14.5	18.2	22.1
Miscellaneous Equipment	7.5	9.0	9.9
Interest During Construction (7%/yr)	3.1	3.7	4.3
Total Capital Cost, 10 ⁶ \$	48.1	56.3	65.1
Specific Cost, \$/kw	303	247	211
Owning and Operating Costs, mills/kwhr			
Capital Charges (17%/yr and 70% load factor)	8.5	7.0	5.9
Maintenance, Labor and Supplies			
Fuel Processing System	0.3	0.2	0.2
Gas Turbines	0.8	0.3	0.3
Steam System	0.2	0.2	0.2
Residual Fuel Oil (\$3.4 #/10 ⁶ Btu)	5.7	5.0	4.2
Busbar Power Cost, mills/kwhr	15.5	12.7	11.1

FIG. 1. CONCEPTUAL DESIGN OF 100-MW CLASS BASE-LOAD GAS TURBINE

EARLY-1980S TECHNOLOGY

TURBINE INLET GAS TEMPERATURE 2600 F

COMPRESSOR PRESSURE RATIO 20:1

AIRFLOW 300 LB/SEC

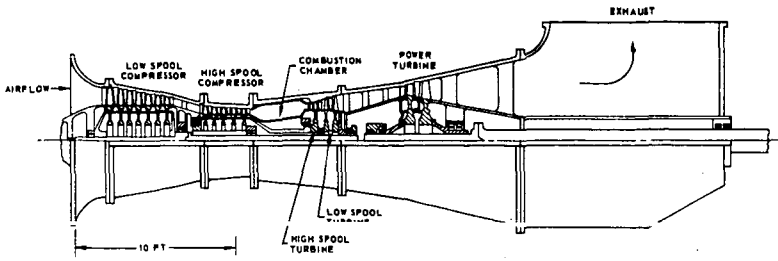


FIG. 2. SCHEMATIC DIAGRAM OF INTEGRATED COGAS/OIL GASIFICATION POWER STATION

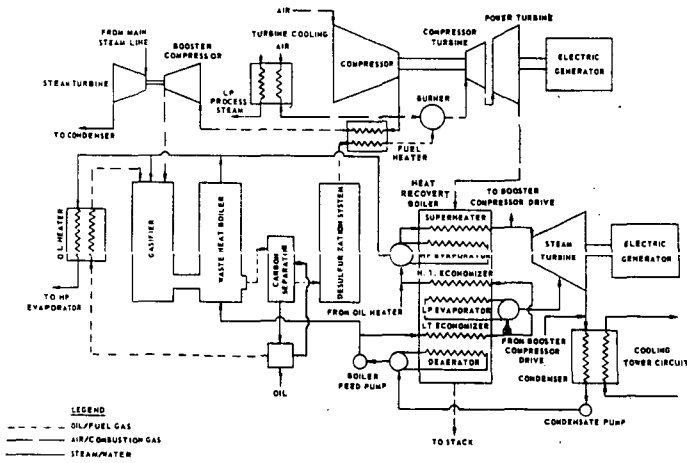


FIG. 3. NITRIC OXIDE FORMATION BY VARIOUS FUELS

PREVAPORIZED, PREMIXED, HYDROCARBON - AIR EQUILIBRIUM
EQUIVALENCE RATIO = 1.0 AIR TEMPERATURE = 1235 R (775 F)
PRESSURE = 14 ATM FUEL TEMPERATURE = 540 R (80 F)

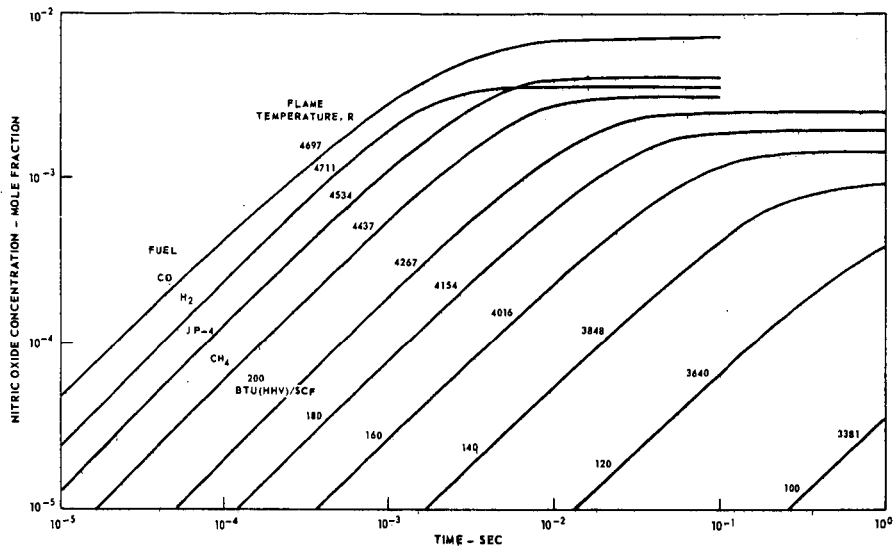


FIG. 4. EFFECT OF GASIFIED FUEL TEMPERATURE ON NITRIC OXIDE FORMATION

PREMIXED, HYDROCARBON - AIR EQUILIBRIUM
EQUIVALENCE RATIO = 1.0 AIR TEMPERATURE = 1235 R (775 F)
PRESSURE = 14 ATM

